Petroleum news

page 5 Q&A: Fairclough wants overview of oil, gas differences for public

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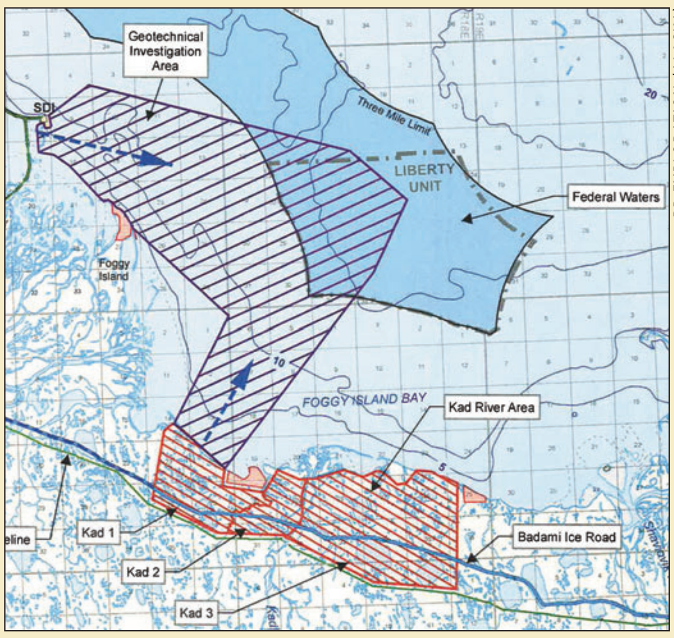

BP EXPLORATION (ALASKA)

BP Alaska to conduct groundwork for possible Liberty development

BP Exploration (Alaska) Inc. is preparing for its second consecutive season of geotechnical drilling in the vicinity of its Liberty oil discovery offshore the North Slope, east of the Endicott field.

Geotechnical drilling doesn't seek to find oil and gas. Rather, it is something done in advance of a construction project.

Whether BP will actually construct an oil development at Liberty remains to be seen. The company in 2012 experienced a serious setback when it was forced to drop an ambitious plan to tap the offshore reservoir from shore with ultra extended-reach drilling.

BP drilled and tested the Liberty No. 1 discovery well in early 1997. The company's most recent publicly stated resource estimate for the Liberty field is "approximately 150 million barrels of recoverable, high-quality light oil."

BP now favors building an artificial island in the Beaufort Sea to develop Liberty, with a subsea pipeline carrying the oil ashore.

The Interior Department has given the company until the

see LIBERTY GEOTECHNICAL page 17

First Nations ramp up sands dispute

Growing tensions between aboriginal communities and the Canadian and Alberta governments are facing a showdown that could see development of northern Alberta's oil sands region tied up indefinitely in legal and civil action.

> *"It's important to save whatever we have — the water and the land for our children."* —Chief Martin Louie of British Columbia's Yinka Dene Alliance

The aboriginal campaign to gain public attention started down a different path Jan. 12 when Canadian singer-songwriter Neil Young held the first of four fund-raising concerts across Canada.

That will be followed on Jan. 23 and 24 when the Fort McKay First Nation hosts a conference to air concerns about environmental impacts, industry practices and the failure to resolve treaty and aboriginal rights.

Fort McKay is seeking permission from the Alberta Court of Appeal to challenge the Alberta Energy Regulator's, AER, approval of the Dover Commercial Project by Athabasca Oil Corp., AOC.

Dover and the nearby McKay River Commercial Project will be operated by Brion Energy, a partnership of AOC and Phoenix Energy, wholly-\ owned by PetroChina, with Dover scheduled to

see SANDS DISPUTE page 15

NATURAL GAS

Equity for state

Legislature asked to approve agreement on LNG project, TransCanada MOU

By KRISTEN NELSON

Petroleum News

Alaska Gov. Sean Parnell has the state moving ahead on a direction he took in 2011 when he asked the North Slope producers and TransCanada to work cooperatively on a liquefied natural gas project for Alaska's natural gas.

SEAN PARNELL

The state is also moving ahead based on a study the Department of Natural Resources had done last year by Black & Veatch which found that a state equity position in an LNG project would benefit the state and the producers.

Parnell told the Alaska Support Industry Alliance Meet Alaska conference Jan. 10 that the state was working with the producers — BP, ConocoPhillips and ExxonMobil — and TransCanada on a proposal for the LNG project which would include a state equity position, a direction the Legislature would be asked to approve in its upcoming session.

And part of moving ahead on a cooperative LNG project was moving beyond the Alaska Gasline Inducement Act, AGIA.

Parnell said the state had amicably agreed with

see EQUITY POSITION page 18

NATURAL GAS

AIDEA chooses MWH

Global infrastructure firm would contribute $85M to North Slope LNG project

By ERIC LIDJI

For Petroleum News

The state is starting negotiations with MWH Americas Inc. to build a liquefied natural gas facility on the North Slope that would serve households across the Interior.

The board of the Alaska Industrial Development and Export Authority unanimously chose the global infrastructure firm on Jan. 14 to be its private sector partner for the Interior Energy Project, a state-backed program to truck LNG to Fairbanks by late 2015.

Among other reasons, AIDEA staff recommended MWH as the best choice because the company proposed the largest private contribution of the three candidates being considered for the project. A larger private investment would allow more of the fixed public

> *The Interior Energy Project aims to provide a long-term supply of natural gas to the Interior at prices 40 to 50 percent below fuel oil by late 2015.*

funding for the project to go toward expanding the distribution grid in the Interior, which would increase the customer base for the LNG plant, according to AIDEA staff.

The AIDEA staff also recommended MWH because of its ability to fund plant expansions and distribution infrastructure, its "considerable technical resources and major project development experience" and its ability to work with customers in the

see LNG PARTNER page 15

EXPLORATION & PRODUCTION

Competitive world

ConocoPhillips executive says Alaska has much potential but must compete

By ALAN BAILEY

Petroleum News

Saying that his company is excited about Alaska, both in terms of future oil potential and the possibility of exporting liquefied natural gas, Matt Fox, ConocoPhillips executive vice president, exploration and production, told the Alaska Support Industry Alliance Meet Alaska conference on Jan. 10 that the Alaska oil industry must compete for investment capital in a world that is seeing a shale oil revolution and where multiple gas projects are lining up to vie for business.

MATT FOX

Fox said that Alaska represents about 16 percent of ConocoPhillips' worldwide production.

"At ConocoPhillips we're very committed to Alaska," Fox said. "It's strategically very important to us. … There is a lot of development potential remaining."

But Fox attributed a new upsurge in ConocoPhillips' investment in Alaska to recent reform in the state's oil production tax.

"This is very much a response to the change in the fiscal regime," Fox said.

The ConocoPhillips capital budget for 2014 in Alaska is $1.7 billion, a $600 million increase over the previous year and the highest level of investment since the 1980s, he said.

"We're putting out money where our mouth is,"

see COMPETITIVE WORLD page 19

contents

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Alaska - Mackenzie Rig Report

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay DS 02-26, workover	BP
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay MPS-39, workover	BP
Dreco D2000 Uebd	19 (SCR/TD)	Alpine CD4-290	ConocoPhillips
AC Mobile	25	Prudhoe Bay Y-10	BP
OIME 2000	141 (SCR/TD)	Kuparuk 2.E-04	ConocoPhillips
Kuukpik	5	Waiting on ice pad for Umiat 23H	Linc Energy Operations Inc.
Nabors Alaska Drilling			
AC Coil Hybrid	CDR-2	Kuparuk 2F-18	ConocoPhillips
Dreco 1000 UE	2-ES (SCR-TD)	Prudhoe Bay	Available
Mid-Continental U36A	3-S	Prudhoe Bay	Available
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay	Available
Dreco 1000 UE	7-ES (SCR/TD)	Kuparuk	ConocoPhillips
Dreco 1000 UE	9-ES (SCR/TD)	Kuparuk	ConocoPhillips
Oilwell 2000 Hercules	14-E (SCR)	Prudhoe Bay	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Prudhoe Bay	Available
Emsco Electro-hoist-2	18-E (SCR)	Prudhoe Bay	Stacked
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Prudhoe Bay	Stacked
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Prudhoe Bay	Available
Emsco Electro-hoist	28-E (SCR)	Prudhoe Bay	Stacked
Oilwell 2000	33-E	Prudhoe Bay	Available
Academy AC Electric CANRIG	99AC (AC-TD)	Moblilizing for winter exploration	Repsol
OIME 2000	245-E (SCR-ACTD)	Oliktok Point	ENI
Academy AC electric CANRIG	105AC (AC-TD)	Mobilizing for winter exploration	Repsol
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site W-18A	BP
Superior 700 UE	2 (SCR/CTD)	Milne Point F-53	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 1C-104	ConocoPhillips
Parker Drilling Arctic Operating Inc.			
NOV ADS-10SD	272	Prudhoe Bay DS 18	BP
NOV ADS-10SD	273	Prudhoe Bay DS W-59	BP

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
BP			
Top Drive, supersized	Liberty rig	Inactive	BP
Doyon Drilling			
Sky top Brewster NE-12	15 (SCR/TD)	Spy Island 14-N6	ENI
Nabors Alaska Drilling			
OIME 1000	19AC (AC-TD)	Oooguruk ODSN-02	Pioneer Natural Resources

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Kenai Land Ventures LLC (All American Oilfield Associates, labor Contract)			
Taylor	Glacier 1	Kenai Loop Drilling Pad #1	Buccaneer Energy Ltd.
All American Oilfield Associates			
IDECO H-37	AAO 111	Kenai Yard	Available
Aurora Well Services			
Franks 300 Srs. Explorer III	AWS 1	D&D yard in Sterling, doing winter maintenance	Available
Doyon Drilling			
TSM 7000	Arctic Fox #1	Doyon Yard, Mobilization	Contracted to ConocoPhillips Winter of 2013/2014
Nabors Alaska Drilling			
Continental Emsco E3000	273E	Kenai	Available
Franks	26	Kenai	Stacked
IDECO 2100 E	429E (SCR)	Kenai	Stacked
Rigmaster 850	129	Kenai	Available
Academy AC electric Heli-Rig	106-E (AC-TD)	Mobilizing for winter exploration	Repsol
Saxon			
TSM-850	147	Ninilchik Unit, Bartolowits pad drilling Frances #1	Hilcorp Alaska
TSM-850	169	Swanson River	Hilcorp Alaska

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
XTO Energy			
National 110	C (TD)	Idle	XTO
Spartan Drilling			
Baker Marine ILC-Skidoff, jack-up		Spartan 151 Upper Cook Inlet KLU#1	Furie
Cook Inlet Energy			
National 1320	35	Osprey Platform RU-1, workover	Cook Inlet Energy
Hilcorp Alaska LLC (Kuukpik Drilling, management contract)			
		Monopod A-11, workover	Hilcorp Alaska LLC
Patterson UTI Drilling Co LLC			
	191	West McArthur River Unit #8	Cook Inlet Energy
Kenai Offshore Ventures			
LeTourneau Class 116-C, jack-up	Endeavor	Port Graham	Buccaneer Energy Ltd.

Mackenzie Rig Status

Canadian Beaufort Sea

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

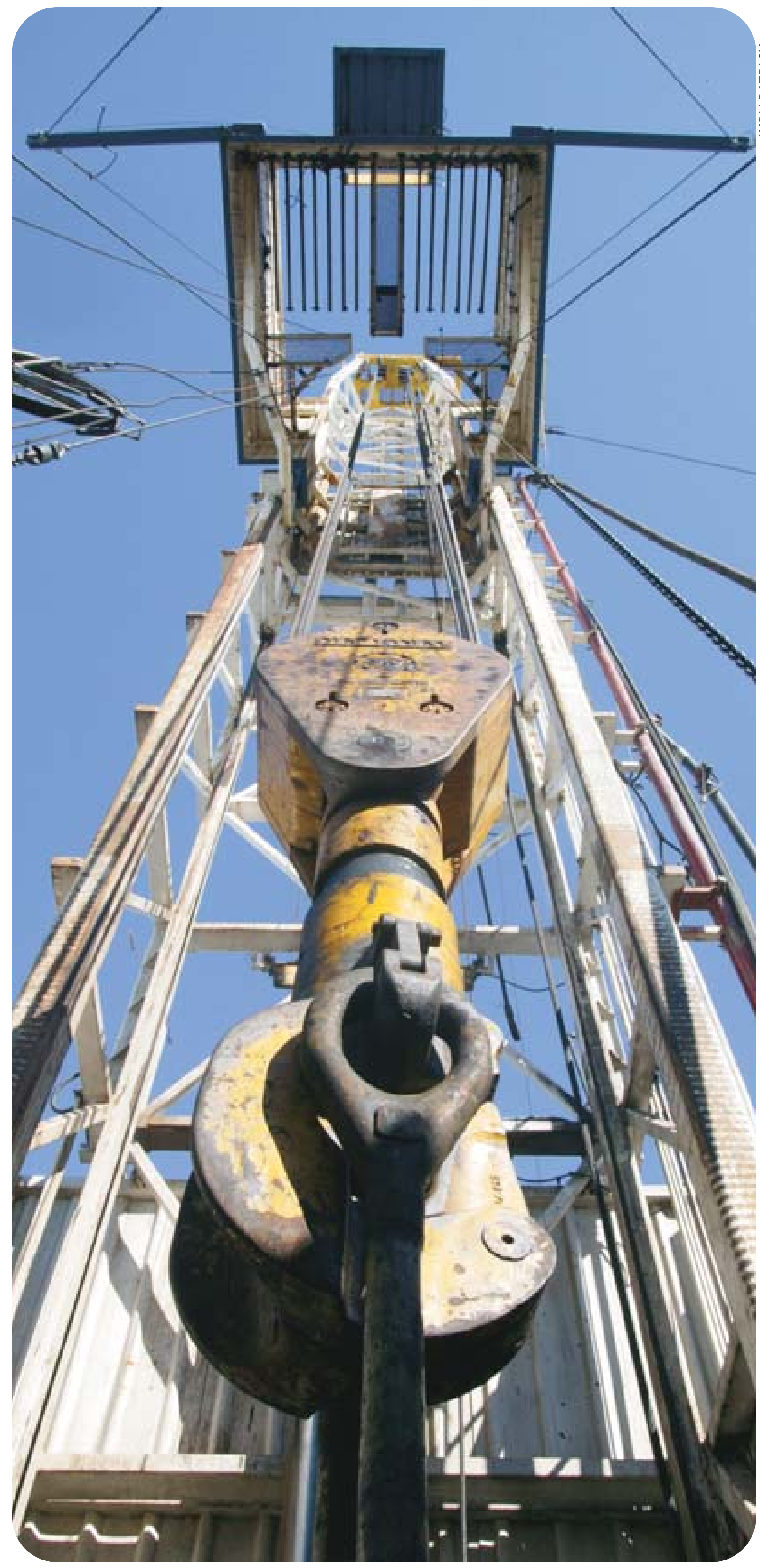
Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita			
TSM-7000	37	Racked in Norman Well, NT	Available

The Alaska - Mackenzie Rig Report as of January 16, 2014. Active drilling companies only listed.

TD = rigs equipped with top drive units WO = workover operations
CT = coiled tubing operation SCR = electric rig

This rig report was prepared by Marti Reeve



JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Jan. 10	Jan. 3	Year Ago
US	1,754	1,751	1,761
Canada	477	282	531
Gulf	55	59	50

Highest/Lowest

US/Highest	4530	December 1981
US/Lowest	488	April 1999
Canada/Highest	558	January 2000
Canada/Lowest	29	April 1992

*Issued by Baker Hughes since 1944

The Alaska - Mackenzie Rig Report is sponsored by:

EXPLORATION & PRODUCTION

AOGCC issues two Repsol permits

The Alaska Oil and Gas Conservation Commission recently issued permits for Repsol E&P USA Inc. to drill two exploration wells on the North Slope, according to records.

The AOGCC issued permits for the Qugruk No. 5 and Tuttu No. 1 wells on Dec. 26.

The AOGCC issued permits for the Qugruk No. 5 and Tuttu No. 1 wells on Dec. 26.

The Qugruk No. 5 well on ADL 391452 will appraise a discovery the company made last year at the Qugruk prospect near the Beaufort Sea coast. The Tuttu No. 1 on ADL 391443 will be an exploration well in the Schrader Bluff/West Sak area near the Kuparuk River unit. Previous exploration efforts in the region called the prospect Rock Flour.

Repsol recently hired Global Geophysical Services Inc. to shoot 3-D seismic this winter over some 293 square miles in the Schrader Bluff area south of the Kuparuk River unit.

Repsol previously announced plans to drill a third well this winter. The proposed Qugruk No. 7 well would also appraise the hydrocarbon discoveries near the Beaufort Sea.

—A copyrighted oil and gas lease map from Mapmakers Alaska was a research tool used in preparing this story.

—ERIC LIDJI

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● EXPLORATION & PRODUCTION

Montney letdown multifaceted

By GARY PARK

For Petroleum News

Holders of exploration rights in Western Canada's Montney oil and gas play couldn't have asked for a better billboard two months ago when regulators rated the formation as one of North America's treasure troves, estimating resources at 3,000 trillion cubic feet of gas, 14.5 billion barrels of gas liquids and 1.13 billion barrels of oil (or 4,500 tcf equivalent).

Some said it was just what they needed to attract a swarm of prospective buyers. Only it hasn't quite worked out that way for a host of reasons.

The big Calgary-based independent Canadian Natural Resources ended a 10-month search for buyers or partners for a quarter of its Montney land holdings by reporting limited and inadequate interest.

The company said Jan. 9 that it received some expressions of interest, but none were of "sufficient interest" to complete a deal for the Graham Kobes package which covers 240,000 acres of the 988,000 acres controlled by CNR and has been estimated by third-party evaluators to hold 6.7 tcf equivalent of contingent resources.

When the process was launched, CNR President Steve Laut said that because the Graham Kobes portion was "somewhat removed from our core Montney asset base, it is prudent to monetize" the property as part of the company's drive to balance its capital spending.

Financing may be issue

Analysts suggested the failure to negotiate a deal reflects the inability of junior companies to secure financing for a big capital project, even though they are the obvious buyers when majors unload assets.

The zone is seen as doubly attractive as a gas source to back LNG export projects and because it is rich in condensates such as propane and butane.

The concern now is whether majors in the Montney will start delaying or shelving their exploration plans, although TD Securities said it expects companies such as ARC Resources, Encana, Tourmaline Oil, Advantage Oil & Gas, Birchcliff Energy and Paramount Resources to continue raising production and reserves.

The zone is seen as doubly attractive as a gas source to back LNG export projects and because it is rich in condensates such as propane and butane.

The Montney is not without hope, given its large-scale transactions such as the takeover of Progress Energy by Malaysia's Petronas for C$6 billion to underpin its Pacific Northwest LNG project, followed by Petronas' deal in November to buy Montney lands from Talisman Energy for C$1.5 billion.

Earlier deals saw Encana reach a C$2.9 billion commitment with Japan's Mitsubishi and ExxonMobil's C$3.1 billion buyout of Celtic Exploration.

M&A activity down sharply

But the sharp decline in merger-and-acquisition activity is another reality, with ATB Financial reporting that oil and gas deals last year hit their lowest level since 2007, with 89 transactions reported at a value of C$8.9 billion, with prices per barrel of oil equivalent production at C$58,769 last year, compared with C$73,400 in 2012 and C$53,271 in 2007.

But analysts said much of the downturn was attributable to limits the Canadian government has imposed on foreign state-owned companies acquiring oil sands assets.

With oil majors unwilling to loosen their purse strings to buy assets in the face of low commodity prices and stern competition from U.S. basins, oil and gas M&As dropped 80 percent last year to US$10.2 billion — considerably more than the TD estimate — compared with US$50 billion in 2012, according to IHS Herold.

Christopher Sheehan, director of M&A research at IHS Herold, told the National Post that a key reason for the downturn was "persistently weak natural gas prices" and the fact that global energy giants piled up US$200 billion in shale and other unconventional resources over the past three years, even though unconventional transactions dropped by more than half last year to US$40 billion. ●

Contact Gary Park through publisher@petroleumnews.com

● GOVERNMENT

Fairclough preparing for gas discussions

Consultants Mayer, Tsafos, formerly with PFC Energy, onboard; senator wants public to understand difference between oil and gas

By STEVE QUINN
For Petroleum News

Sen. Anna Fairclough may be among the busiest of the 60-member Alaska Legislature this year. She serves on the TAPS Throughput Committee, Resources Committee and Finance Committee, meaning she will be on the front lines of most heavy hitting oil and gas bills passing through the Senate.

She's also in charge of Legislative Budget & Audit, which secures help from industry consultants. Last summer, she assembled analysts for a symposium on LNG markets. For the upcoming session, discussions on marketing Alaska's natural gas will be on the forefront, and Fairclough's committee is looking to a pair of familiar names for assistance.

They are Janak Mayer and Nikos Tsafos, formerly of PFC Energy. The two will be paid $250,000 each to be available to the Legislature on a limited basis, plus $13,000 for living expenses.

Fairclough, an Eagle River Republican, discussed how this session could easily be pivotal for advancing a gas pipeline and getting the state's gas to market.

Petroleum News: Let's start with the consultants. So what do you like about these two?

Fairclough: Janak has a history with the Legislature and is trusted. He originally came under contract with the Senate Bipartisan Working Group (previous Senate majority). The way they conduct themselves, in my opinion, is trusted by the House and the Senate. We used them this past legislative session when we were modeling the oil tax issue. I think what I value most about their expertise is their ability to stay away from the political hot potatoes. The really do strive and drive at the fiscal modeling and point out the policy choices versus telling the Legislature which direction to go.

Petroleum News: When consultants get hired, at times the issue of making the consultants available to the Legislature comes up. How will you handle that?

Fairclough: We will send out the same memo we sent out at the beginning of last session that issues the priority level of access to the contractors. We have to manage their time and we have to make sure it's providing benefit to the entire group or, at least as many of the group as possible.


ANNA FAIRCLOUGH

Committee chairman have first priority on anything if there is a bill in their committee and their committee has jurisdiction over the topic, they will get first access to the contractors. I will be managing the use of their time, too. We have specific deliverables that we want to make sure the Legislature has before them. We want to make sure Alaskans, as well as legislators both in the Senate and the House, understand the difference between gas and oil, which is huge.

If you followed the gas symposium or if you go online to the Legislative Budget & Audit's website, we have those overviews there, but it's a lot of information. That information came across an entire week's worth of investment in the Legislature and staff time.

So we want to make sure that they produce for the Legislature and for the general public in Alaska a work product that Alaskans can know that politics aren't involved in this and know that this is a global market and that it functions very differently than oil.

What I want is an overview of the gas symposium that's available to the general public in a much more consolidated manner: Sort of a 101 on the difference between oil and gas. During the symposium they made the audience laugh, (saying) oil is like speed dating and gas is like a long-term commitment. He gave a perfect parable on that. Gas is something that is going to require Alaskans to sign into a long-term agreement at a fixed price to secure contracts like a utility company does. So if you're Enstar, you are looking for 10- and 20-year contracts. If Alaska wants to sell this particular commodity and export it — whether it's export to the U.S. or a foreign country — we are going to have to sign some long-term contracts. So it's important to know that no one is trying to snooker us. This is a standard practice and it's an expectation of someone who is developing LNG that they front load about $5 billion to $7 billion before they see a return. It takes upwards of four years before they see a return from that money. Then the go into a period if the project meets its commitments of build out, then they will have 20 years of low cost anticipated expenses with the revenue starting to repay them for those billions they fronted for years that they had no return on. So they take the risks up front and by taking that enormous risk and not giving shareholders an immediate return — those shareholders have to wait — that's what the contracts require.

Q AND A

Petroleum News: Do you see LB&A holding hearings? It's not uncommon for LB&A to take the lead on energy issues during session as well as the interim like with the symposium.

Fairclough: I'm not sure. Right now I'll be managing this. Both resources committee chairs have told me they are interested in showcasing the differences the gas symposium conversation brought up. It suggested Alaska can compete within pennies of transportation costs to Asia. We can compete if we place our asset — our natural gas — on the water and ship it as far away as Japan and China.

But there are other cost factors involved in getting to Alaska's gas that other nations don't face. Nikos and Janak and others from PFC asked why would any corporation choose Alaska's project over more easily accessed gas. So why wouldn't they go to Texas or somewhere on the West Coast where transportation charges may be similar? Why would they go to Alaska?

What they gave us was a model that showed us different places where different types of businesses invest along the value chain, or the production chain. So let's start at the very end of the market. Alaska could invest by building ships, so we could do that and create a rate of return every time a barge sailed. If we owned a part of that shipping line it would be a fairly low rate for Alaskans. That means the producers of the gas have already made it into LNG, transported it 800 miles plus and have contracts with people to buy.

If we go up the value chain differently and look at the pipeline, it's said in the general public, there is a rate of return between 8 percent and 12 percent that is fairly stable or sustainable for pipeline companies. So if you get a qualified pipeline company to partner and Alaska chose to invest in a pipeline, we may be able to guarantee for the residents of Alaska a rate of return and we can share in some of that profit. Again, low risk because that means we have signed gas contracts and we have the transportation in line and are ready to ship. They aren't going to build a pipeline unless all of that is done.

see FAIRCLOUGH Q&A page 14

● EXPLORATION & PRODUCTION

Apache applies for seismic authorization

Wants to collect more 3-D seismic data in Alaska's upper Cook Inlet as part of major seismic survey program

By ALAN BAILEY

Petroleum News

Apache Alaska Corp. has applied to the National Marine Fisheries Service for an incidental harassment authorization for seismic surveying in Cook Inlet in 2014. The authorization would allow the accidental disturbance of small numbers of marine mammals such as beluga whales during seismic operations. The area where surveying could take place under the terms of the authorization extends out from the coast in the area of Homer and Anchor Point in the southern Kenai Peninsula, and across the entire inlet north from a line extending west from Ninilchik up to an area north of Nikiski.

In 2012 Apache conducted a survey across the more northerly part of the upper Cook Inlet, under the terms of an incidental harassment authorization for that area. Then, in 2013, the company obtained an authorization for surveying to the south of that first area, across a similar area to that envisioned in this year's authorization application. However, the company did not conduct any surveying in 2013 and, with the authorizations only being valid for a year at a time, the company has presumably had to apply for a new authorization.

Multi-year program

Apache is conducting a major multiyear offshore and onshore seismic survey program in the Cook Inlet basin as part of a search for new oil and gas resources in the basin. In addition to the 2012 offshore survey, the company has conducted some land-based surveying on the west side of Cook Inlet. During an August 2013 earnings call Apache CEO Steve Farris said that, while his company remains positive about the Cook Inlet basin, the company was slowing its exploration efforts in the region following disappointing results from the drilling of a well on the west side of the inlet.

Apache has in the past also expressed frustration with the time required to obtain some of the federal permits that it requires to conduct its Alaska survey operations.

The company is conducting its surveys using a state-of-the-art system of wireless, nodal seismic receivers, each of which independently records seismic sound for download into a computer system. Offshore, each node is housed in a small, sealed, disk-shaped container that sits on the seafloor. Air guns towed behind a seismic vessel create the seismic sounds that are reflected off subsurface rock strata, to create an image of the subsurface geology. ●

Contact Alan Bailey at abailey@petroleumnews.com

● EXPLORATION & PRODUCTION

More than $1.8B invested at Pt. Thomson

Alliance gets update on initial production facility work at eastern North Slope field — what's planned for this winter, next year

By KRISTEN NELSON

Petroleum News

Some $1.8 billion has been invested at Point Thomson through October, Gina Dickerson, ExxonMobil's senior project manager at Point Thomson, told the Alaska Support Industry Alliance's Meet Alaska conference Jan. 10, with a total of $4 billion projected by the time the initial production facility goes online in 2016.

The development, the most easterly on the North Slope, is a gas cycling project which will produce up to 10,000 barrels per day of condensate, with gas being reinjected into the reservoir.

For this year's work, the 48-mile ice road from Endicott is going in, and expected to be open by the end of January, Dickerson said.

The gas processing facility modules will come in by barge in the summer of 2015, "and we'll connect those like Legos to make that gas processing facility." —Gina Dickerson, ExxonMobil's senior project manager at Point Thomson

The airstrip was completed in September, replacing what had been just a helipad. With no permanent road to Point Thomson and a limited barging season, "logistics are fairly complicated" and the completion of the airstrip was significant for the project, she said.

This winter the pad will be extended, with gravel haul for that project, and the sealift bulkhead will be finished. Facility modules will be offloaded there when they come in by sealift, she said.

Supporting foundations for support buildings are going in, including the Alaska Clean Seas building and maintenance buildings, as well as well pads and three permanent bridges.

Vertical support members for the export pipeline were installed last winter, Dickerson said, and the 12-inch export pipeline and five miles of gathering lines will be installed this winter. The export pipeline will connect Point Thomson with an existing line at Badami. A permanent camp also went in last year.

The peak workforce on the North Slope this winter will be about 700, she said. The total workforce last year — including the North Slope — was more than 1,100, "and we expect to surpass that this year," Dickerson said.

2015 facility modules

In early 2015 the drill rig will come in and work will be done preparing the pads for the modules.

Three wells are planned, one production well and two injection wells, all directionally drilled.

The gas processing facility modules will come in by barge in the summer of 2015, Dickerson said, "and we'll connect those like Legos to make that gas processing facility."

The initial production facility will have the capacity to cycle 200 million cubic feet of natural gas per day, producing 10,000 barrels per day of condensate. The export gas pipeline has a capacity of 70,000 bpd.

She described the project as "the foundation of future development on the North Slope and integral to the LNG project."

"By 2016," Dickerson said, "we'll be producing through the initial production system and into TAPS."

Not only will the project "add 10,000 barrels a day of liquids in 2016 into TAPS, but we have been building the foundation for the future of Alaska LNG," she said.

The field, discovered in 1977 some 60 miles east of Prudhoe Bay, covers some 150 square miles. The Thomson sand reservoir holds an estimated 8 trillion cubic feet of natural gas and 200 million barrels of condensate. ●

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● ALTERNATIVE ENERGY

USGS finds hot prospect on Akutan Island

New geothermal study yields much higher energy estimate; remote Aleutian island hosts active volcano, tiny village, huge fish plant

By WESLEY LOY
For Petroleum News

A new study from the U.S. Geological Survey finds much greater geothermal energy potential than originally thought on Akutan Island.

Akutan is in the Aleutian chain, just east of Dutch Harbor. The island is home to a tiny village as well as the Trident Seafoods Corp. processing plant, one of the country's largest.

The island also has one of the most active volcanoes in the United States.

Interest in Akutan's geothermal energy potential stretches back decades. Like much of outback Alaska, Akutan is highly reliant on expensive and polluting diesel fuel to generate electricity.

In July 2012, USGS field researchers conducted a five-day survey of the hydrothermal system on Akutan Island.

"The results of our study confirm the existence of a substantial geothermal resource on the island," says a USGS report released Jan. 9.

27 eruptions

The Akutan volcano hosts a geothermal system that includes a fumarole field on the flank of the volcano, and a series of hot springs that discharge close to sea level on the northeast side of the island, USGS said. A fumarole is a steam vent.The volcano has erupted at least 27 times since the late 1700s. The most recent eruption was in 1992, followed by a "seismic crisis" in March 1996.

In the past few years, industry-led geophysical studies and test drilling had proven the existence of a geothermal resource, the USGS says.

Reconnaissance surveys of the hot springs on Akutan Island date back to 1953.

"The first detailed geochemical and geophysical investigations to assess geothermal potential occurred during the early 1980s," the new study says. "Additional investigations at Akutan took place in 1996, several months after the seismic crisis. Studies at Akutan beginning in 2009 were related to renewed interest in geothermal development of the Akutan hydrothermal system for use by the City of Akutan and other population centers on the island."

During the five-day survey in July 2012, samples of gas and water were collected from the hot springs, and gas was collected from fumaroles on the flank of the volcano and from steaming ground on the cone inside the summit caldera.

Promising results

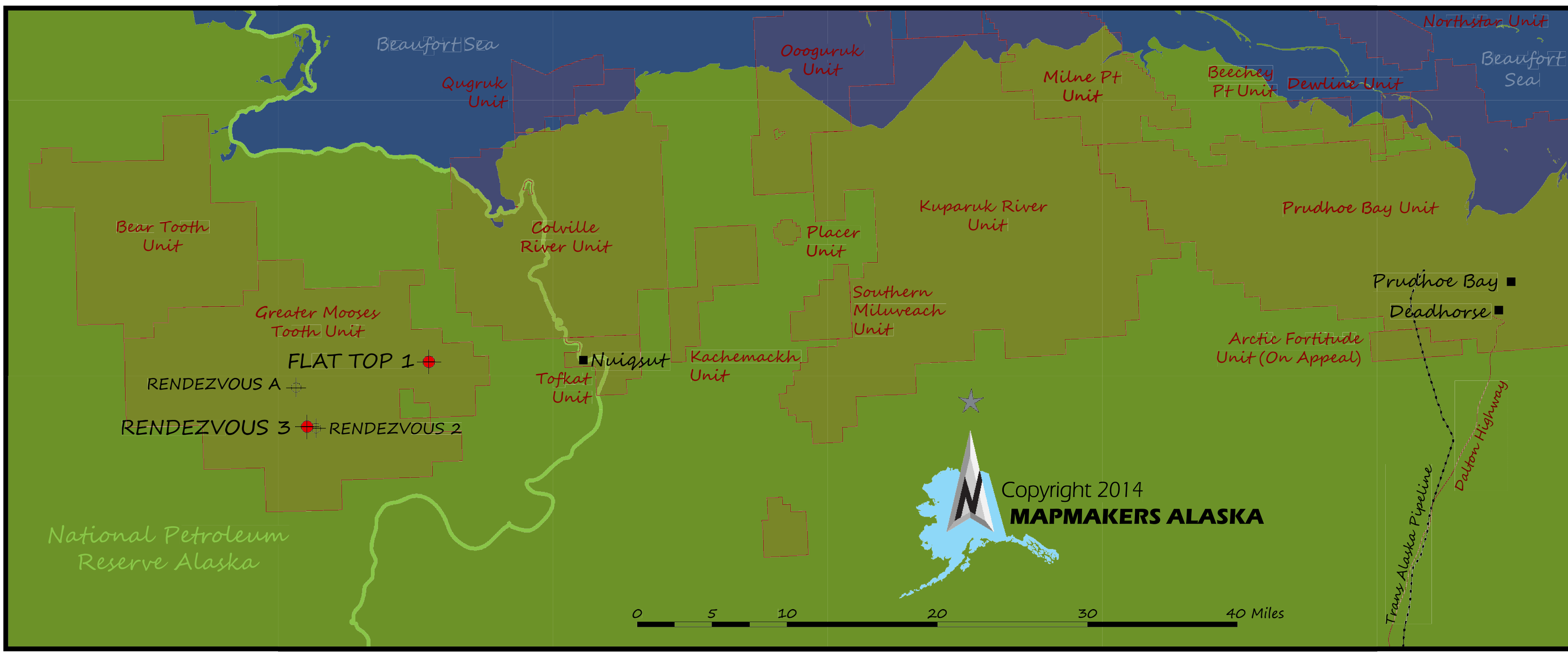
The geochemistry of the hot springs on Akutan Island was studied in detail for the first time since the early 1980s.

"The results from this study document higher concentrations of hydrothermal components in the hot spring waters and an increase in water discharge from the hot spring system," the USGS says in a news release on the study. "The current heat output of the hot spring system is estimated at 29 megawatts — nearly ten times higher than measured in the early 1980s. This large increase may reflect the volcanic and seismic events of the 1990s, and if so, it cannot be considered a short-term anomaly. Modern geothermal plants could use this heat to generate several MW of elec-

see **AKUTAN GEOTHERMAL** *page 11*

DEBORAH BERGFELD, USGS

A hot spring discharges 171-degree water into Hot Springs Creek on Akutan Island.



● EXPLORATION & PRODUCTION

ConocoPhillips planning two NPR-A wells

The company plans to drill the Rendezvous No. 3 and Flattop No. 1 wells this winter at the federal Greater Mooses Tooth unit

By ERIC LIDJI
For Petroleum News

ConocoPhillips Alaska Inc. plans to drill two exploration wells this winter.

The company has applied for permits to drill the Rendezvous No. 3 and Flattop No. 1 wells at its Greater Mooses Tooth unit in the National Petroleum Reserve-Alaska.

ConocoPhillips applied for a U.S. Bureau of Land Management drilling permit in November 2013 to drill Rendezvous No. 3 and in early January for Flattop No. 1.

The Rendezvous well is one of four locations ConocoPhillips staked on two leases near the center of the unit in September 2013. Rendezvous No. 3 would be on lease AA-81784. The Flattop well would be on lease AA-87896, at the eastern edge of the unit.

In its previously announced 2014 budget, ConocoPhillips included preliminary engineering and permitting for the GMT-1 development and two exploration wells.

A decade at Rendezvous

The Rendezvous prospect is among a group of discoveries from the early 2000s.

ConocoPhillips predecessor Phillips Alaska Inc. drilled the Rendezvous A well on lease AA-81803 in April 2000, drilled the Rendezvous No. 2 well on lease AA-81781 in April 2001 and returned to test Rendezvous No. 2 in early 2009. Both wells found oil.

The Rendezvous prospect is among a group of discoveries from the early 2000s. ... The Flattop prospect is a more recent target.

An un-stimulated test of the Rendezvous A in 2001 flowed at a rate of 360 barrels per day of liquid hydrocarbons and 6.6 million cubic feet per day of gas. A test of Rendezvous No. 2 in early 2008 "ranged from about 500 barrels of oil per day to as high as 1,300 barrels of oil per day of high API gravity oil" and gas production rates "averaged about 1.5 million cubic feet per day for each well," according to the company.

In September 2013, ConocoPhillips staked four potential Rendezvous locations: the Rendezvous No. 3 and Rendezvous No. 3 South wells on lease AA-81784, and the Rendezvous No. 3 North and Rendezvous No. 3 North 2 wells on lease AA-81803.

Phillips previously staked a Rendezvous No. 3 well on lease AA-81800.

Flattop relocations

The Flattop prospect is a more recent target.

In 2001, Phillips Alaska staked a Tuvaaq No. 1 well and a Tuvaaq No. 2 well on AA-81798, a small lease adjacent to AA-87896, but ultimately drilled neither. In October 2008, ConocoPhillips staked a Flattop No. 1 well on the same lease, AA-81798. In August 2013, ConocoPhillips began permitting a GMT-1-B2 oil well on lease AA-81798.

When the BLM approved the Greater Mooses Tooth unit in 2008, the unit boundaries partially included AA-81798. ConocoPhillips expanded the unit in 2009 to include four leases along the eastern edge: AA-87896, AA-81797, AA-81796 and AA-81795.

In October 2012, ConocoPhillips staked a new Flattop No. 1 well location on AA-87896 and also a Flattop No. 2 well on AA-81796, but ultimately drilled neither well.

With the expansion, the BLM required that ConocoPhillips spud an exploration well — targeting the upper Jurassic — on the additional acreage by the third quarter of 2015.

The current Flattop No. 1 well proposal would fulfill that requirement. ●

—A copyrighted oil and gas lease map from Mapmakers Alaska was a research tool used in preparing this story.

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● LAND & LEASING

Land rush slows in Western Canada

By GARY PARK

For Petroleum News

There was a time when Canada's resource provinces and territories could count on a useful cash infusion — consistently in the billion-dollar-plus range in Alberta, British Columbia and Saskatchewan — from the sale of oil and natural gas land rights.

Not anymore.

Returns across the country slipped to C$992 million last year from almost C$1.4 billion in 2012, with Western Canada's Big Three raking in the lion's share at C$990 million.

Alberta collected C$698 million, compared with C$1.12 billion in 2012 and a staggering C$3.5 billion in 2011 — posting its lowest return since C$477 million in 2002.

In the oil sands, Alberta sold only 147,000 hectares last year for a mere C$28 million, compared with the record 1.5 million hectares which fetched C$1.96 billion in 2006.

British Columbia, despite positioning itself as the leading source of gas for LNG exports, auctioned off C$225 million of rights, C$85 billion better than 2012, but far short of the benchmark C$2.7 billion in 2008 from its hot shale and tight gas plays.

Saskatchewan collected a modest C$67 million last year, compared with C$102 million in 2012 and not even close to its take of C$1.2 billion in 2008 when exploration companies started awakening to the Bakken potential.

Among the other regions, Manitoba dropped to C$2.03 million from C$11.3 million, while work commitments contributed C$19.2 million in the Northwest Territories, underpinned by the Canol shale play in the Central Mackenzie Valley, and Saskatchewan added C$4.61 million.

Per-hectare average prices moved in two directions, with Alberta slipping to C$306 from C$354 in 2012, while British Columbia surged to C$1,886 from C$1,020 and Saskatchewan climbed to C$605 from C$266.

Calgary investment bank Peters & Co. said in a recent note that successful bids in Western Canada generated an average C$397 per hectare, compared with C$391 in 2012.

Deals seen as barometer

Land deals are seen as one of the strongest barometers of upstream confidence and company plans for drilling within the next year.

Many factors have contributed to the drop off in overall returns, led in Alberta by a cooling down in the feverish scramble to secure rights in the Duvernay formation, with its high liquids content.

Already delivering sweeping budget cuts, the Alberta government is unable to count on land returns to soften those blows.

For the fiscal year ending March 31, 2014, it has been counting on C$1.15 billion from land, but the most recent budget update showed it was C$30 million short of the C$211 million in had expected in the first quarter of the budget year.

Calgary investment bank Peters & Co. said in a recent note that successful bids in Western Canada generated an average C$397 per hectare, compared with C$391 in 2012.

Saskatchewan Energy and Resources Minister Tim McMillan is confident that companies operating in his province are shifting their emphasis from accumulating assets to the exploration and development phase.

Noting that Saskatchewan was ranked as the top jurisdiction in Canada for oil and gas investment policies in the Fraser Institute's latest annual study, he said that vote of confidence from the industry "shows that our government is taking the rights steps to ensure we remain competitive in Canada and globally." ●

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● EXPLORATION & PRODUCTION

BOEM asks Shell for more information

Still has some questions about Chukchi Sea exploration plan; wants more details about Noble Discoverer oversight and air emissions

By ALAN BAILEY

Petroleum News

The Bureau of Ocean Energy Management, or BOEM, wants some further details from Shell about its revised Chukchi Sea exploration plan, the agency notified the company on Jan. 14. Shell wants to restart exploration drilling in the Chukchi and in early November submitted a revised plan to BOEM for approval — Shell started the drilling of a Chukchi Sea well in 2012 under the terms of an earlier version of the plan.

The agency has to confirm that the revised plan is complete before initiating a public comment period as part of the plan approval process. On Nov. 29 the agency sent Shell some questions, spelling out a list of items that the agency considered to be missing from the plan.

> *BOEM requires more information relating to modifications and repairs to the Noble Discoverer, the drillship that Shell is chartering from Noble Corp. for the Chukchi Sea drilling.*

Shell responded to those questions on Dec. 20. And in its Jan. 14 notification BOEM asked Shell for clarification of some of the points in Shell's response.

Noble Discoverer

BOEM requires more information relating to modifications and repairs to the Noble Discoverer, the drillship that Shell is chartering from Noble Corp. for the Chukchi Sea drilling. The U.S. Coast Guard had determined some safety and environmental non-compliance issues with the Noble Discoverer following Shell's 2012 drilling season. The vessel had also suffered engine problems. The vessel has since undergone repair, upgrade and modification in an Asian shipyard.

BOEM says that it will accept a certificate of compliance from the U.S. Coast Guard as evidence that the deficiencies in the Noble Discoverer have been corrected. But the agency still wants Shell to explain how in future the company will apply adequate management oversight of the vessel, to ensure that any operational deficiencies are quickly detected and fixed.

Air emissions

BOEM's latest request for further

see **CHUKCHI PLAN** page 10

LAND & LEASING

State issues Tolsona basin license

The Alaska Department of Natural Resources issued an exploration license in December 2013 to Ahtna Inc. for the Tolsona basin, according to recently released land reports.

The five-year exploration license covers some 43,492 acres in the Glennallen area and requires Ahtna to spend at least $415,000. The license is listed as ADL 392209.

In late October 2013, a Cook Inlet Energy Inc. exploration license in the Susitna basin north of Anchorage expired as the lands were converted to 25 traditional leases.

The five-year exploration license covers some 43,492 acres in the Glennallen area and requires Ahtna to spend at least $415,000. The license is listed as ADL 392209.

Also in Cook Inlet, independent investors Lee Higgins and Terri L. Stull Higgins are looking to transfer a 0.25 percent royalty interest in seven leases to Shawn Batholomae.

In the Nenana basin, the department issued 21 leases to Doyon Ltd., which had previously held an exploration license in the region. In November 2013, a former partner in the exploration program, Cedar Creek Oil & Gas Co., asked to transfer a 0.25 percent overriding royalty interest in 38 leases in the basin to Windmill Canyon LLC.

On the North Slope, ConocoPhillips is seeking to transfer a 22 percent working interest and 19.25 percent royalty interest in six onshore leases to Anadarko E&P Offshore LLC.

The leases — ADL 392341, ADL 392342, ADL 392343, ADL 392348, ADL 392349 and ADL 392350 — are located along a bend in the Colville River just south of Nuiqsut.

ConocoPhillips and Anadarko have long been partners on the North Slope.

The department issued two Beaufort Sea leases to the Armstrong Oil & Gas Inc. subsidiary 70 & 148 LLC. The leases are ADL 392538 and ADL 392539.

The department approved a transfer of a 10 percent working interest and 8.75 percent royalty interest in two Devon Energy Production Co. LP leases at the Point Thomson unit to the unit operator ExxonMobil Corp. The leases are ADL 47562 and ADL 47567.

—A copyrighted oil and gas lease map from Mapmakers Alaska was a research tool used in preparing this story.

—ERIC LIDJI

NATURAL GAS

Enstar to install gas line under Kenai River

Enstar Natural Gas Co. is planning to install a gas distribution pipeline underneath the Kenai River to extend service to several subdivisions on the river's south side.

Anchorage-based Enstar is the main gas utility serving Southcentral Alaska.

It will be a plastic pipe, 6 inches in diameter, operating at 60 pounds per square inch gauge, Enstar's application says.

The company has applied to the Alaska Department of Natural Resources for an easement across the Kenai at river mile 34 in the Sterling area.

A DNR public notice published Jan. 10 says the gas main will be installed with horizontal directional drilling.

It will be a plastic pipe, 6 inches in diameter, operating at 60 pounds per square inch gauge, Enstar's application says.

Boring beneath the Kenai will begin on the north side of the river at Huske Street. The bore will extend about 950 feet, with 360 feet beneath the river and the rest beneath the banks. The bore will maintain a minimum depth of 20 feet below the river, Enstar says.

Construction is planned for between February and August.

The Kenai is famed for its runs of Chinook and sockeye salmon. Development along the river is a longstanding concern because of the potential impact on salmon habitat.

—WESLEY LOY

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CHUKCHI PLAN

information also includes a list of items relating to air emissions from Shell's planned drilling operations. The agency has taken over air permitting for the Arctic outer continental shelf from the Environmental Protection Agency. But, rather than separately approving an air permit for Shell's drilling project, BOEM will review Shell's air emissions data for legal compliance as part of an overall review of the company's exploration plan.

BOEM has, however, accepted Shell's explanations regarding quite a few of the issues that the agency had raised, including questions regarding a reduced frequency of blowout preventer testing; a need for more detail about an expanded man camp planned for Barrow; and a need for more information about the Polar Pioneer, the semi-submersible drilling rig that Shell plans to station at Dutch Harbor, as a backup rig for relief-well drilling.

Integrated operations plan

In addition to its exploration plan, in November Shell submitted to BOEM an integrated operations plan for its planned Chukchi Sea drilling — BOEM required Shell to file this plan as a consequence of one of the findings of a Department of the Interior review of the company's 2012 Arctic exploration activities. BOEM has now completed its review of the integrated operations plan and has submitted a list of 14 comments on the plan, in addition to the request for further information on the exploration plan.

The comments include a request for a completion schedule for activities listed in the plan; a request for some further detail on decision-making authority in the event of unplanned interruptions to drilling operations; and a request for further clarification on lines of communication and accountability between Shell and its contractors — the Department of the Interior review criticized Shell's management of the various contractors involved in its drilling program.

Shell hopes to restart its Chukchi Sea exploration drilling during the summer of 2014. However, the company has expressed some uncertainty about whether the restart will occur in 2014 or 2015 and has said that it will need to complete all of the necessary permitting for its latest drilling fleet before drilling can take place. ●

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AKUTAN GEOTHERMAL

tricity. One MW of electric power would supply the needs of about 750 homes."

A geothermal reservoir is presumed to underlie the fumarole field, and a chemical geothermometer yields temperatures near 356 degrees Fahrenheit for the aquifer that feeds the hot springs, the USGS says.

"Geothermal development for electrical power generation could take advantage of either a high-temperature, but probably deeper resource, or a moderate-temperature resource at relatively shallow depth," says Deborah Bergfeld, a USGS geochemist and lead author of the report.

The USGS doesn't go into the cost that would be involved with a geothermal energy development on Akutan. Presumably, the price tag would be many millions of dollars, with the project requiring some sort of government subsidy.

The 18-page report and photos are available online at http://on.doi.gov/1dhG0zh. ●

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TIM PLUCINSKI

Akutan volcano

FINANCE & ECONOMY

US oil output stabilizing prices

The U.S. Energy Information Administration, or EIA, has commented that oil production growth in the United States contributed to the relative stability in global oil prices seen in 2013. As U.S. production climbed, with oil transportation infrastructure improvements easing the flow of oil from new shale oil plays in the Bakken, Permian basin and the Eagle Ford, and from Cushing Okla., in 2013 West Texas Intermediate spot prices climbed 4 percent to an average price of $98 per barrel. At the same time, North Sea Brent prices dropped 3 percent to $109 per barrel, EIA said.

"Brent prices came down under downward pressure as rising U.S light sweet crude oil production reduced the need for U.S. imports, thereby increasing supplies of Brent-quality crude oil available to the global market," EIA said.

In 2013 U.S. domestic oil production reached its highest level in 24 years, increasing by 1 million barrels per day, an increase greater than the combined increases achieved by the rest of the world, and the largest observed production increase in U.S. history, EIA said. And, for several weeks, U.S. production exceeded imports, the first time this has happened in nearly two decades, the agency said.

At the same time China has overtaken the United States as the largest importer of crude oil. Unplanned oil supply disruptions around the world averaged 2.6 million barrels per day in 2013, with producers in the Organization of Petroleum Exporting Countries accounting for 1.8 million barrels of this figure. In 2013 higher U.S. production coupled with some elevated Saudi Arabian production stabilized prices by offsetting outages. OPEC liquid fuel production dropped by 0.9 million barrels per day, while non-OPEC production grew by more than 1.4 million barrels per day.

—ALAN BAILEY

● EXPLORATION & PRODUCTION

Ahtna seeks Copper River gas supplies

Native corporation looking for affordable energy for people in a region that has been losing population because of energy costs

By ALAN BAILEY
Petroleum News

Ahtna Corp., the Native regional corporation for Alaska's Copper River valley region, has compiled an energy strategy and plan for its region, with a search for natural gas being part of the plan, Joe Bovee, Ahtna land and resource manager, told the Alaska Support Industry Alliance Meet Alaska conference on Jan. 10. Bovee said that the prime purpose of seeking natural gas is to establish an affordable source of energy for the region, although if a sufficiently large find were made it might also be possible to export gas from the region.

"Our primary focus is to lower utility costs for most consumers," Bovee said.

In October Ahtna gained a state exploration license for gas exploration in 72 square miles of state land, west of the town of Glennallen. The corporation is currently reprocessing about 80 miles of existing 2-D seismic data for state land and anticipates acquiring a further 13 to 14 miles of new seismic data. The intent is to identify a potential well location in 2014, with a view to drilling a well in 2015 or 2016, Bovee said.

In October Ahtna gained a state exploration license for gas exploration in 72 square miles of state land, west of the town of Glennallen.

Loss of population

Bovee said that the region had lost 10 to 15 percent of its population in the last three to four years, that numerous schools had closed and that many restaurants and other businesses had closed because of the high cost of energy. Ahtna's energy planning had found that energy-related data for the region was outdated but, more importantly, had identified the region's people as the region's most important resource, Bovee said.

If commercial quantities of gas cannot be found, the corporation anticipates importing liquefied natural gas into the region. Ahtna is in the process of preparing an application for an RCA certificate of public necessity and convenience to do that, Bovee said.

Gas potential

The Copper River basin, a broad area of sedimentary rock lying under the Copper River valley region, is thought to be gas prone. Its geology is similar to that of the prolific Cook Inlet basin to the southwest — in particular the Mesozoic strata of the basin are broadly equivalent to strata that have generated oil and gas in the Cook Inlet region.

The basin is one of six Interior basins that qualify for state exploration tax credits, Bovee said, commenting that the tax credits are essential to the funding of the Copper River gas exploration.

During the past 50 years or so 11 wells were drilled in the Copper River basin and all of these wells had gas shows, Bovee said, adding that 640 miles of 2-D seismic had been shot in the basin during the same period. The most recent of the wells was drilled between 2005 and 2007 by Rutter and Wilbanks near the town of Glennallen. Although this well found a gas reservoir, the drillers encountered severe unresolved difficulties resulting from excessive downhole pressures and the flow of water into the well.

Ahtna's new exploration license encompasses land not far from the Rutter and Wilbanks well. The corporation is particularly interested in the gas potential of the Nelchina sands, a highly pressured, porous and permeable gas-bearing sandstone that occurs in faulted blocks over an area of roughly 120 square miles. The corporation has already reprocessed much of the existing seismic data that exists for this area — potential gas targets exist at depths ranging from 4,000 feet to 12,000 feet, Bovee said.

Other energy sources

The Ahtna energy plan also encompasses other possible energy sources. The corporation has erected 11 weather observation towers and has used these to identify two to three sites with commercial grade wind, Bovee said. One wind tower for power generation has been erected at Cantwell, on the south side of the Alaska Range. Weather observations have also indicated excellent residential solar power potential.

There are five hydroelectric projects in Ahtna's region, including the planned massive Susitna-Watana dam, Bovee said.

There are some geothermal energy prospects near Glennallen and in the western portion of the Wrangell Mountains to the east. In particular, near Glennallen are some mud volcanoes, a rare phenomenon found worldwide only at Glennallen and at a location in South America — testing in the mud volcanoes has revealed temperatures of up to 300 F and the emission of methane at one spot, Bovee said.

The region also has an estimated 4 million tons of accessible biomass fuel, the equivalent of 300 million to 400 million gallons of fuel oil and, in principle, sufficient fuel to heat the region's buildings for the next 150 years. But it would require much energy to dry the biomass material sufficiently for use as a fuel, Bovee said. ●

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GOVERNMENT

Dear Mr. President: Let's lift export ban

Murkowski urges president to clear way for shipping out US crude oil; LNG and pipeline projects also need action, she says

By WESLEY LOY
For Petroleum News


SEN. LISA MURKOWSKI

U.S. Sen. Lisa Murkowski is now taking her recommendation to the very top.

The Alaska Republican sent a letter to President Obama urging him to lift the ban on exporting domestic crude oil.

Murkowski, in her Jan. 14 missive, also touched on other energy matters she believes need attention.

Murkowski is the top-ranking Republican on the Senate Energy and Natural Resources Committee. Majority Democrats control the committee.

Lifting the export ban was part of a Jan. 7 speech Murkowski gave at the Brookings Institution, a Washington, D.C., think tank. She warned of a coming oil glut that could crimp the nation's crude production.

Export reforms sought

With her letter to Obama, Murkowski enclosed a copy of her speech as well as her white paper outlining her ideas on reforming energy export policy.

"In particular, I would draw your attention to the status of our nation's hydrocarbon trade," Murkowski wrote the president. "While exports of our natural gas and petroleum products have grown, our work is far from finished, and our policies are, in some cases, far from adequate."

The letter continued: "Despite the obvious geopolitical, economic, and environmental benefits of building out our nation's (natural gas) liquefaction capacity as soon as possible, the Department of Energy continues to slow-walk its approval of export licenses to our allies. The Keystone XL pipeline, which the State Department estimated would support over 42,000 jobs, remains unapproved even after years of delay. I once again urge you to take immediate action on these infrastructure projects, which you have generally promised to champion."

Administration might agree

Obama's energy secretary, Ernest Moniz, has suggested it might be time to reconsider the oil export ban, in place since the 1970s when the Arab oil embargo shocked the nation.

Support for removal of the export ban, however, faces considerable opposition from some members of Congress, as well as some refinery operators.

The ban generally precludes oil exports, though there are exceptions including one that applies to oil from Alaska's Cook Inlet and North Slope.

"The necessity of lifting the prohibition on crude oil exports ... presents us with a rare opportunity to work together in a bipartisan fashion to address this situation before it becomes a problem," Murkowski wrote Obama. "Lifting the ban will help create jobs, boost the economy, and keep our production at record levels."

She added: "While I believe you retain the executive authority necessary to lift the ban on crude oil exports, if you need legislative support from the Congress in order to do so, you will always have a willing partner from Alaska." ●

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EXPLORATION & PRODUCTION

US drilling rig count up by 3 to 1,754

Oilfield services company Baker Hughes Inc. says the number of rigs drilling for oil and natural gas in the U.S. rose by three the week ending Jan. 10 to 1,754.

The Houston firm said in its weekly report that 1,393 rigs were drilling for oil and 357 for gas. Four were listed as miscellaneous. A year ago there were 1,761 active rigs.

Of the major oil- and gas-producing states, Oklahoma gained 14 rigs, New Mexico, Utah and West Virginia were up two, while Kansas and Wyoming rose one apiece.

Texas lost seven, Colorado and North Dakota each were down six, Louisiana dropped by two, and Alaska and Pennsylvania were off one. Arkansas, California and Ohio were unchanged.

The U.S. rig count peaked at 4,530 in 1981 and bottomed at 488 in 1999.

—ASSOCIATED PRESS

FINANCE & ECONOMY

Oil prices ease after sharp gains

Oil prices eased Jan. 16 but remained above $94 a barrel after sharp gains a day earlier on improved demand in the U.S.

Benchmark U.S. crude oil for February delivery was down 8 cents at $94.09 a barrel at mid afternoon Kuala Lumpur time in electronic trading on the New York Mercantile Exchange. The contract surged $1.58 to settle at $94.17 in New York Jan. 15.

Brent crude, used to set prices for international varieties of crude, was down 44 cents at $105.83.

The U.S. Energy Department reported that oil supplies fell bigger than expected by 7.7 million barrels the week ending Jan. 10, the seventh straight decline. It was sharply above market expectations of a 1.6 million barrels decline.

—ASSOCIATED PRESS

continued from page 5

FAIRCLOUGH Q&A

Again, what the contractors asked at the symposium, is why Alaska? You can make all of those investments in British Columbia, in Oregon, in California or in Louisiana. All of those things are still available. So why Alaska when the gas has to be transported over such a long distance? If you back up to the North Slope, the most risky project in the value chain for the producers to be successful is the LNG.

Those projects, as I understand, typically again require $4 to $7 billion of upfront assets but they see no rates of return on. Those projects, typically, if someone hasn't built a project before, cannot come online when anticipated. So there can be delays. If you look at Australia and Papua New Guinea, those are places building large LNG plants and they are not coming in and being completed on time for a variety of reasons. And those cause costs of the actual commodity — the gas — to go up when they don't complete the project on time.

For me, when I was listening, it seems like it's the LNG is risky for the producer, but it also has the potential for the greatest long-term return for Alaska's dollar. And it makes it less risky for someone who wants to produce on the North Slope if the state was a partner in that. You wouldn't be a partner in that until you have those confirmed shipping contracts, either.

I know this is a long version, but it's important to note that there are different spots along the value chain that Alaska can invest in. We can also invest our royalty gas. So I think that's what we have to discuss. We also have to keep in mind, wherever we choose to invest or if we choose to invest, we have to weigh like the private sector developer would do, the risk versus reward and where is our comfort level for risk?

I said a long time ago in the finance committee; I would give up my Alaska dividend to be part of a pipeline. There is very low risk and a standard rate of return once you make that risk. You don't have a lot of downside. There could be a natural disaster, like an earthquake that would damage the line. But overall, the last 30 to 50 years, pipelines have been safe investments.

Petroleum News: That leads to the next question, and you've spoke to some of that, what are your thoughts on the Black & Veatch report that suggests taking an equity interest in the project?

Fairclough: I'm not sure. I think we need to look closely at the Black & Veatch report. It's part of the work we negotiated with (Janak Mayer and Nikos Tsafos) is that review of the report to make sure Black & Veatch is grounded in current affairs globally and that the assumptions they made in the report are accurate. I specifically asked our contractors to look at that Black & Veatch report and true up the assumptions that are being made in that report. That's not anything to do with the governor or the quality of that report. It's just as the Legislature, we should be taking a look at these issues and the numbers associated with those issues on our own. We want to fact check and make sure we agree with the assumptions used in that report. It's just a re-check in a global market when you are looking at billions of dollars when you are looking at the assumptions the Legislature agrees with.

Petroleum News: OK, still on the administration, what are your thoughts on the governor's announcement to set aside AGIA and the separation from TransCanada?

Fairclough: Well, I voted no on the license. I voted yes on trying to extend the opportunity for someone to bid on it. When TransCanada came forward, it was my belief that TransCanada would have Canadian interest in front of Alaskans interest. That's just a personal feeling. I think we are all loyal to our countries. They are a business and they are loyal to their shareholders but I didn't think Alaskans interest would be first. They have done everything technically to meet the conditions of their license. But for them to continue in Alaska's value stream, I think that the governor is making the right decision. If they are a pipeline company who wants to bid and be part of it, they can bid like anyone else. I think they are a quality pipeline company with professionals who do a great job for their business. But there are other pipeline companies out there, so it is my hope that TransCanada will exit gracefully and allow Alaskans an opportunity to provide for ourselves.

Petroleum News: On the point of a company not having Alaska's interest, there's long been the concern in some circles that oil companies consider interests outside of Alaska first. Does that differ from TransCanada?

Fairclough: I think oil companies like any companies have shareholder interest first. I look at any organization that comes before the Legislature and I have to put on a filter that I know they may not all be operating in Alaska's best interest. That's supposed to be my job. I'm supposed to be able to filter that out and see that they are advocating for a business reason that benefits them — from their perspective. From my perspective, I'm looking to see if they offer a benefit that's worth investing in for Alaska. We have hundreds of people who try to gain access to the Legislature each year, whether it's electrical generation and infrastructure improvements. That's trying to benefit a utility, but in the end it could benefit ratepayers. Sometimes it's trucking natural gas to Fairbanks. That's an interest for Fairbanks but it may not be as high an interest for Anchorage, but it's still a valid interest for the community advocating for that. Certainly I don't think everyone has Alaska's interest first, but the Legislature should.

Petroleum News: You've already covered a great deal on what's ahead for the session, is there anything else you consider a priority for the session?

Fairclough: I believe it's in the governor's interest to introduce a tax bill. I mean it's going to be generated from the administration. The administration is the one who has going have to manage it. It needs to go through committees so that we understand 360 degrees how it affects the administration, those businesses who might be involved as well as the general public.

As I've said, gas is very different from oil and we need to lock arms with the general public so that we all understand how different that is and what that means to Alaska. I'm all about good business decisions that benefit the people of Alaska long term.

Quite frankly, the governor needs to introduce a gas taxation bill. We will not be able to get long-term gas commitments without a tax bill so that there is certainty when producers go to their corporate boardrooms either in Texas or in London. If they go to those board rooms and they can't articulate that actual margin of profits that they can see or at least a continuum of profits that they might see over a period of time, we are not going to be able to compete. Gas is very long-term as opposed to oil that can be on the spot market and can be sold very quickly. Gas cannot. Gas is streaming as feedstock, or it's feeding into a refinery long term or it's feeding into a utility to move turbines for decades. So it's very different.

If the governor does not step up; if the producers don't do what the governor has asked them to do as far as alignment goes, I hope the Legislature will take up the issue at least in talking about the components that would be involved in gas taxing so that the people of Alaska have the opportunity to discuss those issues.

One of the other things that came up in the gas symposium, is the actual window opening and that is China and Japan are out shopping for gas contracts. Those contracts are for 2023 and 2025. China and Japan were one of the highest growth potentials for selling. To have those contracts coming up, that fits in Alaska's plan very well. That's why we need to push hard — now. If it takes four years to build something, there is very little wiggle room and knowing those projects in Australia and Papua New Guinea have build out times that push that window, we have to push now.

Petroleum News: What does the change with AGIA do for the in-state line and the folks at AGDC?

Fairclough: We've been trying to drive the projects together for some time. I think you'll see further alignment. As budgets get tighter, the general public is talking about it more. By that I mean, appropriations that seem to be going toward similar types of projects. The governor has done a great job to make sure there is value in each project going forward so they weren't duplicating work, that we were trying to make sure that there was specific tasks each organizations were doing that would merge together into one project. I think we should prioritize our investments so we don't have multiple people doing the same things.

Petroleum News: OK, let's close with oil. SB21 still remains a hot topic with the referendum to repeal the tax regime. Both sides are starting to dig in a little more with public messages. What's your take on this?

Fairclough: I think we have to get beyond sound bites. This issue is so important to the livelihood of the state and the people of Alaska that in the end, the people will make the right decision, they will vote no. In between voting no and the current conversation, it's going to be hard to hear the real facts. The facts as I understand it are SB21 is faring better than ACES under lower prices. We would not have seen more money under ACES. For those thinking about voting yes, I hope they take time to compare actual apples to apples to see what they would receive with less production and with a lower price. It's my understanding that SB21 is more durable and we are now producing equal or better in the form of revenue at lower oil prices. Why this is important and why we passed it this past legislative session, just like fracking changed the access to natural gas and oil in the entire U.S., if you look back we were looking at net imports of oil, and those import numbers grew. Now that conversation has changed dramatically and now we hear we have 100 or 200 years of natural gas available. What that may mean is the price for oil and natural gas will be lower. If that stays lower, that means SB21 has anticipated and has responded appropriately to that lower level of revenue coming in for that commodity. ●

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LNG PARTNER

Interior, such as the two natural gas distribution utilities and the regional electric cooperative.

Several AIDEA board members described the MWH proposal as being the most straightforward and least risky of the three and praised the deep pockets of the company.

The AIDEA board spent nearly two hours in executive session before voting.

Ranking three choices

After soliciting interest in the project last year, AIDEA received proposals in November 2013 from MWH Americas Inc., Pentex Alaska Natural Gas Co. LLC and Spectrum Alaska LLC. AIDEA staff spent the intervening months comparing the three proposals.

Now, AIDEA wants to sign a letter of intent with MWH by the end of the month, produce a development agreement by mid-March and close the deal by the end of May.

Given that quick timeline, the AIDEA board ranked the remaining proposals by preference. Should negotiations with MWH fall apart, AIDEA would begin negotiations with Pentex Alaska Natural Gas Co. LLC and then with Spectrum Alaska LLC.

The Interior Energy Project aims to provide a long-term supply of natural gas to the Interior at prices 40 to 50 percent below fuel oil by late 2015. As envisioned, the project involves a 9 billion-cubic-feet North Slope LNG facility, a trucking operation to the Interior, storage and re-gasification facilities in the Fairbanks North Star Borough, and relationships with local heating and electric utilities, as well as industrial customers.

According to AIDEA staff, all three proposals met the requirements of Senate Bill 23, which provided some $332.5 million in grants, loans and bonds to help bring the Interior Energy Project into fruition. All three proposals would yield "substantial savings" for Interior households currently using heating oil, some 55 percent, or $2,800 per year.

Specifically, SB23 provided the Interior Energy Project with a $57.5 million capital appropriation, up to $125 million in low interest loans from the Sustainable Energy Transmission and Supply Development Fund and up to $150 million in AIDEA bonds.

The MWH proposal released in November 2013 used the entire $125 million SETS loan and up to $85 million in private equity at 65 percent debt to fund the plant at a 12 to 15 percent return. MWH based its proposal on high-end AIDEA estimates for capital and operations costs, which are both likely to change as the project moves from analysis into actuality.

Loan to FNG

The AIDEA decision follows other recent movement on the Interior Energy Project.

The Regulatory Commission of Alaska recently gave the municipal Interior Alaska Natural Gas Utility permission to distribute gas throughout much of the Fairbanks North Star Borough including the city of North Pole, and encouraged the Pentex-subsidiary Fairbanks Natural Gas LLC to expand within its existing service area in Fairbanks.

To accommodate that expansion, AIDEA has also approved a $20 million loan to help FNG build a liquefied natural gas storage and distribution facility in Fairbanks. The 5 million gallon facility would allow FNG to increase its local sales by 40 percent, or 400 million cubic feet per year. Perhaps more important to the isolated and weather-prone residents of Fairbanks, the facility could hold between 10 and 15 days of supplies.

The $20 million loan would cover a little more than half of the $35 million project, with Northrim Bank loaning the remaining $15 million. Northrim Bank asked AIDEA to participate in the project. The AIDEA loan is for 25 years at 5.68 percent interest.

The loan goes to FNG and its wholly owned subsidiary Cassini LNG Storage LLC. The wholly owned Pentex subsidiary Titan Alaska LNG LLC is guaranteeing the loan. The loan gives AIDEA a first lien on all assets of FNG, Cassini and Titan. The finished storage facility would be worth some $55 million, according to a third party appraisal.

The project would be eligible for $15 million in state tax credits, but the AIDEA loan requires FNG to invest $5 million of those credits into expanding its distribution grid.

The storage facility is a crucial component of the Interior Energy Project, but AIDEA staff said the project would be economically viable without the Interior Energy Project.

The project is expected to create 90 construction jobs and five permanent jobs. ●

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SANDS DISPUTE

grow in four phases over the 2015-22 period to 150,000 barrels per day and ultimately reach 250,000 bpd, while the McKay project is targeting an initial 150,000 bpd, aiming for 250,000 bpd.

Buffer zone requested

The First Nation is pressing for a buffer zone between the Brion project and the aboriginal lands, pointing to a possible legal precedent that would have widespread consequences for the oil sands industry.

Separately, the Athabasca Chipewyan First Nations group in the northeastern corner of Alberta, which is organizing the Young concerts, is trying to block Shell Canada's proposed 100,000 bpd expansion of its Jackpine mining operation.

In approving the Shell proposal, a Joint Review Panel of the AER and Environment Canada set 22 conditions — mostly tied to water usage, environmental protection and the rights of First Nations — that would extend to mining areas, related processing facilities, utilities and infrastructure.

A spokesman for the Athabasca Chipewyan community said publicity from the fund-raising drive will ensure the First Nations' argument is heard by a wider audience and reinforce guarantees in the Canadian Constitution covering aboriginal rights to land and habitat and a mandatory duty-to-consult clause applying to developers and governments.

Stale Tungesvik, president of Statoil's Canadian division, which may shift its focus from the oil sands to Newfoundland's offshore, said the oil sands industry could play a leading role in raising education standards and providing training for skilled jobs to reduce chronic unemployment among aboriginals.

Constitutional issues

Douglas Eyford, in a special report to Prime Minister Stephen Harper in December on the role of aboriginals in West Coast energy development, said the "constitutionally protected rights of aboriginal Canadians (must be) taken into account."

He said the essential steps include: Building trust, fostering inclusion, advancing reconciliation and setting up a tripartite

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Petroleum news

Oil Patch Bits

Growth drives change at Price Gregory and CONAM

In response to market demand in the Alaska construction industry, Price Gregory and CONAM Construction are making the following staffing and organizational changes to better respond to client needs.

BOB STINSON

DALE KISSEE

Robert "Bob" Stinson has been named senior vice president of Price Gregory International, Alaska Division. Stinson has 38 years of experience in Alaska, primarily with Price Gregory and CONAM Construction, where he has been instrumental in developing both companies' roles as well-respected, long-term oil, gas and industrial construction companies. In his new position, he will lead the organization in all aspects of its Alaska operations. Stinson is taking over Price Gregory responsibilities from Dave Matthews who will be retiring in March. In addition to serving the oil and gas sector, he will be introducing a new Industrial Power Division in response to awards of EPC electrical power plant contracts in Alaska and Hawaii.

Dale Kissee has been promoted to president of CONAM Construction Co., where he will continue to manage the operation of the company's capabilities in construction and maintenance of oil and gas, and infrastructure projects. Kissee is a 38-year veteran in the oil and gas industry, with more than 34 years spent with the Price Gregory and CONAM companies in Alaska. Supporting Kissee are Bill Binford, CONAM's North Slope area manager and Mike Sheppard, CONAM's Cook Inlet area manager.

KENNETH YOCKEY

Kenneth Yockey, P.E., has joined Price Gregory International, Alaska Division as its oil and gas construction manager. He will be responsible for managing the oil and gas initiatives of the company and continuing to support strong client and labor relations for existing and new projects under Stinson. Yockey has more than 20 years of experience as a senior corporate manager on construction projects throughout the state of Alaska, including extensive experience with the development of the North Slope oil fields.

Olgoonik/Fairweather team awarded ANIMIDA III contract

Olgoonik/Fairweather LLC in conjunction with a team of scientists from the University of

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LIBERTY GEOTECHNICAL

end of 2014 to submit a new development and production plan for the federal leases in the Liberty unit. The regulators have cited 2020 as the goal for first oil.

On Dec. 18, BP submitted a request for approval of a winter geotechnical and seafloor investigation to the Bureau of Ocean Energy Management.

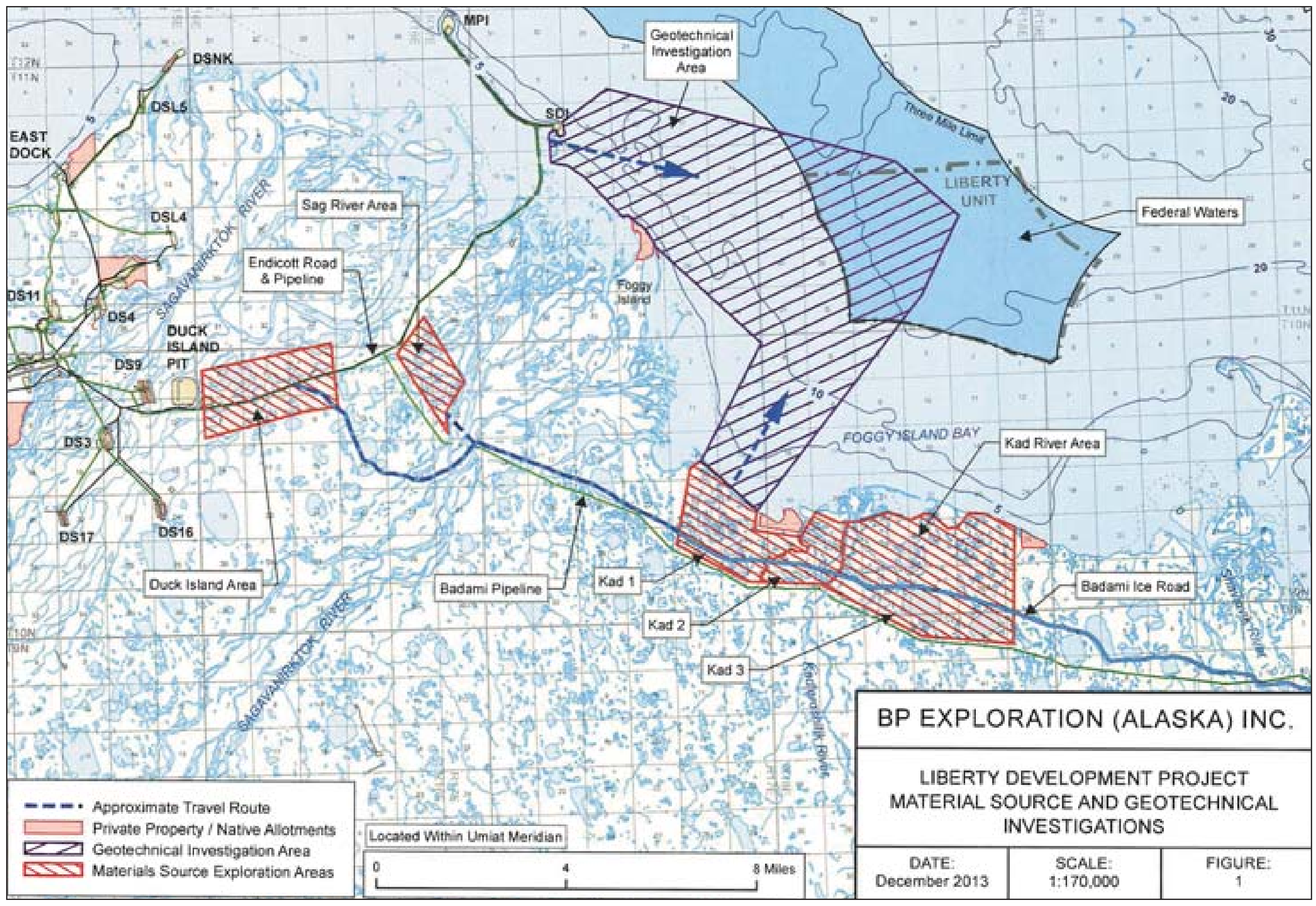
BP plans a range of activities on land and on the frozen sea, with the work to begin in March and end in early May.

The program will involve drilling holes onshore to investigate potential sources of gravel that would be needed for construction.

Offshore, BP plans to drill numerous holes to gather soil information for "possible future offshore pad locations," and for evaluating pipeline routes, the company's submittal to BOEM says.

A field team will drill about 40 geotechnical boreholes from the sea ice to depths of about 100 feet below the seafloor, BP's plan of operations says.

The geotechnical investigation area covers both federal and state waters.



Surveying the seafloor

For the seafloor investigation, BP proposes dropping a camera or a remotely operated vehicle through holes augured in the ice to capture video images of features such as rock or kelp cover.

"About 40 locations will be drilled," BP says, adding the total number of sites examined will depend on weather and sea ice conditions.

BP completed a similar program of geotechnical investigations in early 2013, BP Alaska spokeswoman Dawn Patience told Petroleum News.

The company this year plans to monitor the ice pack, in light of horizontal movement of the land-fast ice formation seen in Foggy Island Bay during the 2013 geotechnical program.

"This year's program will characterize the extent of surficial movement of the ice pack," BP's plan of operations says. Up to four remote sensors mounted on steel poles will be installed in the ice pack.

The geotechnical investigation presents certain challenges unique to the Arctic.

Crews will use forward-looking infrared radar, or FLIR, to look for denning polar bears prior to work activities. A trained bear guard will be employed.

Workers also must take care to avoid seal lairs and breathing holes.

—WESLEY LOY

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OIL PATCH BITS

Alaska Fairbanks, the University of Texas at Austin, the Florida Institute of Technology, Battelle Memorial Institute and Kinnetic Laboratories Inc., has been awarded the Bureau of Ocean Energy Management contract to continue environmental monitoring research in the Beaufort Sea. The project is titled Arctic Nearshore Impact Monitoring in the Development Area. ANIMIDA III is a two-pronged monitoring project that includes a separate effort involving the monitoring of Boulder Patch kelp beds in the area around Camden Bay.

The group will conduct comprehensive scientific studies to characterize the lease areas and surrounding environs of the Beaufort Sea that expand beyond past sampling efforts conducted during prior ANIMIDA I and ANIMIDA II work. The duration of the project will span from 2014 to 2017, with field programs planned during the open-water seasons of 2014 and 2015 and through-ice sampling events in the spring of 2015. Data synthesis is planned for years three and four, with the 2014 field season data informing the research for subsequent years.

The ANIMIDA III scientific program will involve interdisciplinary research including benthic ecology, chemistry and physical oceanography. The chemistry work will evaluate the presence of oil industry contaminants, including a selection of metals and hydrocarbons in sediments and biological tissues, to detect possible changes as a result of future oil and gas activities.

Olgoonik/Fairweather LLC is a joint venture with Olgoonik Oilfield Services, a subsidiary of the Alaska Native corporation for the Village of Wainwright and Fairweather Science for more information visit www. fairweather.com/environmentalscience.

Editor's note: All of these news items — some in expanded form — will appear in the next Arctic Oil & Gas Directory, a full color magazine that serves as a marketing tool for Petroleum News' contracted advertisers. The next edition will be released in March.

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SANDS DISPUTE

energy working group of the federal and provincial governments and First Nations.

Chief Martin Louie, of British Columbia's Yinka Dene Alliance, said the aboriginal community is facing a limited choice: Either go to court or erect roadblocks.

"It's important to save whatever we have — the water and the land for our children," he said.

The sense of urgency in the oil sands region is gathering pace, even at a time when the industry is unsure about its future, with two more large-scale projects rolled out in the last month.

Imperial Oil has filed a regulatory application for its C$7 billion Aspen project to produce 135,000 barrels per day by using solvents for a thermal recovery operation to recover about 1.1 billion barrels of bitumen.

To allow time to introduce the technology and carefully allocate capital, Imperial expects to proceed in three phases of 45,000 bpd each, bringing the first onstream by about 2020 and counting on a 40-year lifespan. A final investment decision is expected in 2017.

Husky Energy has announced plans to build two projects of 10,000 bpd each in the Lloydminster area of Saskatchewan, using steam to extract the heavy crude.

The company said it expects its overall thermal operations will yield 55,000 bpd by 2016, a year earlier than its original goal.

—GARY PARK

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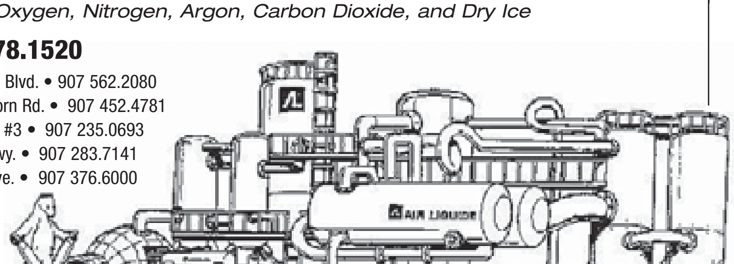

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EQUITY POSITION

TransCanada to move from the AGIA license, which TransCanada was awarded in 2008, into commercial agreements. In addition to a memorandum of understanding with TransCanada, he said he expected a commercial agreement to be signed "very soon" to provide "a transparent set of terms and road map for Alaskans to consider. That commercial agreement is known as a heads of agreement for the Alaska LNG project," he said.

Both documents, the MOU and the heads of agreement or HOA, became public Jan. 15 and available online at www.dor.alaska.gov.

MOU

The MOU, signed Jan. 12 by TransCanada and the commissioners of Revenue and DNR, covers the transition between AGIA and a commercial agreement. It states that a commercial agreement between the state and TransCanada would benefit the state but terms proposed in the MOU would not be effective until passage of enabling legislation.

The MOU proposes that TransCanada would hold an ownership interest in the midstream portion of the Alaska LNG project (the pipelines and the gas treatment plant) and the state would have an option to acquire a share of that interest, up to 40 percent. TransCanada would provide gas processing and transportation services for the state's share of gas.

Once enabling legislation becomes effective and commercial agreements are executed for the pre-FEED (pre-front-end engineering and design) phase, the commissioners would initiate the process of making a determination under AGIA that the licensee's AGIA licensed project is uneconomic.

HOA

The heads of agreement, signed by the state, the producers and TransCanada Jan. 14, says the parties are currently negotiating commercial agreements for pre-FEED to move to the next phase of the project, and wish to ramp up to the pre-FEED phase, estimated to cost more than $400 million.

Enabling legislation, as defined in the HOA, includes a confidential process so the administration could participate in developing terms for contracts, and would allow for contract terms addressing such issues as state participation; a state share of gas (royalty in kind and gas in lieu of production taxes); property taxes; upstream costs and lease expenditures; in-state gas deliveries; state LNG or gas sales contracts; and Alaska hire.

Upon passage of acceptable enabling legislation, the HOA says pre-FEED work would ramp up in the second quarter of 2014 and take between 18 and 24 months to complete.

Upon completion of pre-FEED work, the parties would individually decide whether to proceed with the Alaska LNG project.

Legislative review

The agreements, signed for the state by Natural Resources Commissioner Joe Balash, Revenue Commissioner Angela Rodell and Alaska Gasline Development Corp. President Dan Fauske, will be reviewed by the Legislature.

Parnell told Meet Alaska that he would ask the Legislature to take up bills authorizing the Department of Natural Resources to modify leases; allow the state to enter gas shipping agreements; revise the production tax for natural gas; authorize AGDC to participate in liquefaction; and make other changes.

AGDC, which continues work on an in-state gas pipeline project, will participate in the LNG project through a subsidiary approved by the AGDC board.

"This commercial agreement, with its transparent set of terms, is Alaska's roadmap to developing our vast gas reserves," Parnell said in a statement after the agreements were released.

Rodell said the "agreement is essential to establishing the commercial structure of this project" and will allow investors to move the project forward.

Balash said that the state, as an equity partner, would "play a critical role in setting the terms for decades-worth of gas production from the North Slope" with the goal of maximizing "the royalty value of the state's gas on behalf of all Alaskans."

Fauske said the agreement "reaffirms AGDC's central role as Alaska's gas pipeline company and further enables the corporation to explore every option for delivering gas to Alaskans at the lowest possible cost," adding that AGDC is "moving full-steam ahead" with the in-state project, which is on schedule for an open season in 2015.

Reactions to the HOA from producers

Statements from the North Slope producers highlighted the benefits they see from state participation.

In an emailed statement BP said: "This agreement integrates the resources of all parties behind this potential Alaska LNG project. It sets out guiding principles for the parties to negotiate project-enabling contracts once the Alaska Legislature passes the enabling legislation."

ExxonMobil said: "The Heads of Agreement is another positive milestone and sets guiding principles, terms and conditions to progress work on the Alaska LNG project. State of Alaska participation throughout the value chain will improve commercial alignment; provide the state with a seat at the table on the commercial terms of the project, as well as generate additional revenue for the state."

ConocoPhillips said: "The intent of the HOA is to provide Alaskans with a roadmap for how the parties intend to progress the Alaska LNG Project. Consistent with the principles in the HOA, ConocoPhillips looks forward to working with the Parnell Administration and the Alaska Legislature to advance discussions on fiscal and commercial terms to help progress the project."

Legislators comment

House Speaker Mike Chenault, R-Nikiski, and Rep. Mike Hawker, R-Anchorage, legislative movers behind AGDC, put out a statement on the agreements.

Hawker said he was "pleased to see this tangible evidence of alignment among all stakeholders in an Alaska gas project. We've tried many times to advance gas commercialization, but this is different. The stakeholders are working as partners with common interests, rather than as adversaries."

Chenault said this progress on a gasline project is "exactly what I envisioned four years ago with HB 369 — alignment between commercial interests and Alaska's needs." But construction of a project is years away, he said, and "it's important that AGDC continue progressing an in-state gas pipeline."

"The best line is a big line in partnership with industry, but Alaska must be ready to take care of Alaskans if a big line doesn't meet industry's commercial benchmarks down the road."

Members of the Senate majority were also encouraged by the agreement.

Sen. Cathy Giessel, R-Anchorage Hillside/Turnagain Arm/North Kenai, called this "a historic time for Alaska." "We have now moved the ball to the next 10-yard line," she said in a statement.

Senate President Charlie Huggins, R-Wasilla, said the approach was "completely different" than the way things have been done in the past. "This is a transparent process where basic principles are agreed on up front by all parties, and then we develop principles and legislation which will guide us to a binding commercial agreement."

"This is what getting a big project done looks like," said Senate Finance Co-Chair Pete Kelly, R-Fairbanks. "Whether we take baby steps or giant steps, the important thing is we are always taking the necessary steps to build that gas line."

It's a changing world

How did Alaska come to sign a heads of agreement for the Alaska LNG project? And how did it end up bailing on AGIA?

AGIA no longer fits the project, Parnell said Jan. 10 at Meet Alaska.

AGIA was a reaction to an agreement negotiated under the Stranded Gas Development Act, which itself, the governor said, was a reaction to an agreement privately negotiated between the Knowles administration and BP for a royalty reduction at the Northstar oil field.

"The administration presented the royalty contract for legislative approval in what we thought at the time as legislators was a 'take it or leave it' deal," Parnell said, referring to a time in the late 1990s when he was a legislator.

Because of concerns over what the administration might negotiate for a gasline deal, legislators passed the Stranded Gas Development Act, giving the administration the authority to negotiate, "but with some sideboards," Parnell said, and requiring that the deal come back to the Legislature for approval.

The Murkowski administration used the act to negotiate fiscal terms for a gasline with the producers, but the deal was rejected by the Legislature, Parnell said: "Neither legislators nor the public trusted the lengthy, private negotiation process, nor the contract terms" in the contract.

Birth of AGIA

The result was AGIA, passed under the Palin administration in 2007 at a time when "Alaskans' trust in state government had vaporized. Gasline negotiations had gone badly, and public trust over that and other issues was at an all-time low," Parnell said.

The mindset when AGIA passed was that all the terms of a deal had to be negotiated up front, he said, and with that in mind, AGIA enshrined "must haves" in statute in exchange for Alaska participation in a gasline project.

But times changed. When AGIA was passed, parties were not working cooperatively toward a project.

"AGIA changed that," Parnell said. After TransCanada was selected as the AGIA licensee, ExxonMobil joined TransCanada and the two worked cooperatively with the state. Separately, BP and ConocoPhillips were cooperating on the Denali gasline project.

But something else changed.

AGIA's focus was a to move gas through Canada to the Lower 48, addressing what was believed to be a sharp decline in U.S. natural gas production, Parnell said.

Changing markets

But at the same time AGIA was passed, in 2007, gas volumes in the Lower 48 began to increase dramatically as shale gas began to be developed.

When did it become obvious that Alaska North Slope gas wasn't needed in the Lower 48?

Public acknowledgement came in 2011 when BP and Conoco closed down the Denali project, Parnell said.

Meanwhile, demand in the Pacific Rim was strengthening, the governor said.

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EQUITY POSITION

Parnell said he "set Alaska on a different course" in 2011, challenging the producers and TransCanada to back an LNG project which would provide gas for Alaskans and LNG to be marketed worldwide.

The first step involved getting the gas: resolution of the Point Thomson litigation, the governor said. He characterized the state's actions there as building trust and reward "through incremental, verifiable performance of work commitments."

The state brought a related principle of "commensurate, proportionate commitments" to the gasline discussions, Parnell said.

"When it comes to the gasline, the state will verify progress and make new commitments through the legislative process at multiple points, and the companies via their board room decisions at multiple points."

Parnell said he then called on the companies "to harden their numbers, and to identify a pipeline project and work schedule," a benchmark met last fall when the companies selected Nikiski as the terminus for the gasline.

With the vote of the AGDC board of directors to create a subsidiary to participate in the Alaska LNG project, Parnell said: "For the first time in Alaska's history, all the necessary parties have aligned to make an Alaska gasline project go — three producers, a pre-eminent pipeline builder, AGDC — an entity that can carry whatever state interest is required of it, and state agencies responsible for the people's royalties and taxes." ●

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COMPETITIVE WORLD

he quipped, referencing ConocoPhillips' advocacy for Alaska tax reform.

Worldwide strategy

Characterizing his company's overall worldwide strategy as consisting of a portfolio of oil and gas opportunities coupled with decisions over how to allocate capital between those opportunities, Fox said that ConocoPhillips will spend a total of $16 billion worldwide in 2014. About 10 percent of that money will be spent on maintaining the integrity of the company's operating assets, improving operational efficiency and reducing operational costs. Another 45 percent of the spend will pay for development programs, such as the type of infill drilling using coiled tubing that is done in Alaska. Development projects will lift what would otherwise be a worldwide production decline rate of about 10 percent per year to total production that remains approximately constant. And then about another 30 percent of the investment will be channeled into major infrastructure-led projects, such as the new CD-5 development in the National Petroleum Reserve-Alaska, Fox said. These major projects should lead to a compound growth rate of 3 to 5 percent in ConocoPhillips' production over the next five years, he said.

The remaining 15 percent of capital investment will go into exploration, seeking new oil and gas resources to develop.

Shale oil

In terms of oil development, Alaska now faces significant competition for investment dollars from the rapidly growing shale oil industry in places such as Texas and North Dakota.

"There really is a revolution going on in U.S. oil production," Fox said, showing a graph depicting Texas oil production rocketing up in the past couple of years, North Dakota production increasing rapidly and California production overtaking that of Alaska.

Fox said that ConocoPhillips is heavily involved in both the Eagle Ford play in Texas and the Bakken play in North Dakota, the two plays that have led the shale oil revolution. Wells in the Eagle Ford can achieve initial oil flow rates of 1,000 barrels per day, with up to 1 million barrels of oil ultimately flowing from each well. The finding and development costs run to about $20 per barrel, with cost of oil supply from the plays being in the range of $40 to $50 per barrel, Fox said.

"We didn't even know this play existed five years ago," Fox said, commenting that his company will likely spend $8 billion in the Eagle Ford and $4 billion in the Bakken over the next five years. In addition to several other shale oil provinces, the Permian basin play is growing fast, with its production possibly overtaking that of the Eagle Ford and the Bakken in the next five years, Fox said. And then there are other oil development opportunities, such as in offshore deepwater situations.

"That is the context in which we have to look at Alaska's competitive situation," Fox said.

LNG market

When it comes to the market for liquefied natural gas, or LNG, there are currently wide disparities in gas prices around the world, Fox said. Following the shale gas revolution, gas sells in the United States at a price in the range of $3.50 to $4.50 per million British thermal units, a price range that seems likely to prevail for some time to come. By comparison, gas is priced at around $10 in Europe. In Japan, where gas prices are indexed to oil prices and nuclear power issues have caused a faster-than-expected increase in demand, the price is around $16.

"There's clearly a prize in trying to access and take advantage of this (price) differential," Fox said. "Everybody in the industry knows there's a prize there. … The global LNG business is shaping up to be really very, very competitive."

And as LNG projects around the world line up to meet the future LNG demand, so-called "brown-field sites," sites with an existing gas infrastructure that can be expanded at relatively low cost, appear to have a significant competitive advantage. Fox showed a graph indicating that sites like this, in places such as Qatar, Indonesia, Malaysia and Papua New Guinea, can cover their outlay in capital invested at gas prices somewhere in the range of $4 to $8 per million Btu.

Competitive landscape

On the other hand, "green-field sites," where wholly new infrastructure is needed, require significantly higher priced gas. These sites, in regions such as western Canada, the U.S. Gulf Coast, East Africa and Arctic Alaska, all appear to need broadly similar gas prices, somewhere around $11 or $12.

"The key is that there's an enormous amount of gas that can come to the market at the same cost of supply," Fox said. "The competitive landscape for LNG is going to be really fierce."

In this environment an Alaska LNG project will have to make sure that it controls its costs, working within an appropriate fiscal regime — investment also requires long-term confidence in that fiscal regime, he said.

But, with 24 trillion cubic feet of natural gas in just the Prudhoe Bay field gas cap, Alaska gas definitely presents an opportunity.

"There is definitely potential for us to develop LNG here in Alaska," Fox said.

Tax change

At the same time, the recent change in the Alaska oil production tax is a key to new oil exploration and development, he said, commenting that ConocoPhillips has already added a new drilling rig to the Kuparuk unit and is the process of bringing in a second new rig to the unit. The company is laying gravel for a new Kuparuk drill site and is permitting for a potential Greater Mooses Tooth project that the company hopes will follow its CD-5 development in the National Petroleum Reserve-Alaska — the company is also conducting exploration in the reserve.

The major increase in capital investment in Alaska this year is going into development drilling, development projects, major projects and exploration, those components of ConocoPhillips' overall strategy that target increased oil production, Fox said.

"It's a step change," he said.

And, to address the need to tackle production decline in what are now old fields on the North Slope, ConocoPhillips has a really committed Alaska work force, including some of the company's most creative people, he said. Past achievements include the use of 4-D seismic data to find new oil in old fields; taking a world leadership position in the use of coiled tubing drilling and steerable drilling; running one of the largest miscible gas flood operations in the world; and experimenting with other enhanced oil recovery techniques, Fox said. ●

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